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GENERAL OVERVIEW
OF PRODUCTION AND EXPLORATION ACTIVITIES

By
R. Horsfield

For The
Mackenzie Valley Pipeline Inquiry

Inuvik, N.W.T.

January 1976



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GENERAL OVERVIEW

Mr. Commissioner:

Slide 1 In the interest of establishing a basis for discussion of "Producer" operations, we felt that it might be desirable to summarize how companies like ours go about finding and producing oil and gas. With your permission, I will describe the exploration, development and production processes of our industry, using slides for illustration. My comments will be generally applicable; specific references to the Arctic will be noted as such.

I will then review the history of "Producer" activities in the Mackenzie Valley area of the Territories.

The Exploration Process

Crude oil and natural gas are natural forms of hydrocarbons found in the earth. They are called hydrocarbons because they consist of molecules of hydrogen and carbon atoms. They are found only in sedimentary basins; those very old ocean basins which have gradually filled with sediments during millions of years. Plant and animal remains buried in the sediment turn into hydrocarbons under increased heat and pressure.

Slide 2 Therefore, the first step in the exploration process to discover these hydrocarbons is simply to locate the sedimentary basins. The sedimentary areas of Canada are shown in brown on this map.

Slide 3

When formed, the hydrocarbons occupy the pores of the rock just as water is held in a sponge. They may be squeezed out by the weight of continuing sedimentation, or they may just flow away through interconnected pore spaces. To be of interest to the oil industry, they must have somehow accumulated in places where they have been trapped. These traps are usually porous sand or limestones that are sealed by layers of clay or shale which prevent the fluids from moving any further. These traps are called reservoirs.

Therefore, the second step in the exploration process is to try to find out if there might be suitable reservoirs in these basins. This is done by inspecting nearby mountains and river banks where the rock layers are exposed to view. It involves a few geologists who roam the sedimentary area collecting samples of rock and recording technical information which will help them to infer the kinds of rocks that might exist within the buried part of the basin. Some measurements of the gravitational and magnetic forces of the earth are made to help estimate the thickness of the sediments.

Preliminary estimates of how much oil and gas might be found in a basin are based on this minimal information, in comparison with other basins around the world. It might be of interest for you to know that the sedimentary rocks of the world can be divided into about 500 basins. Of these, three contain over half the world's hydrocarbon resources. Perhaps less than 100 of the basins contain a significant amount of hydrocarbon, and several hundred contain no

hydrocarbons or negligible amounts. Hence the existence of a basin is no assurance of hydrocarbon reserves; conversely, the discovery of oil or gas in a basin can be very significant.

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The next step in the exploration process is to obtain an exploration permit which involves a financial commitment such as an annual rental fee or work obligation. Seismic surveys will likely be started as soon as possible, unless a specific drilling location is apparent.

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Seismic is used to locate underground reservoir traps. It works like sonar and radar. Vibrations created by charges placed near the surface are reflected off underground layers of rock and recorded by very sensitive detectors laid out on the surface. This gives us some indication of the structure of the earth below.

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A typical seismic picture is shown on this slide. It extends over seven miles across the top and several thousand feet down below the surface. Although a layman can see the suggestion of rock layers in the picture, only expert geophysicists can sort out the many complex factors involved in the interpretation.

Several seismic surveys may be run over the same area for various reasons. A reconnaissance survey is usually run first, with the seismic lines spread several miles apart, to get a broad picture of the basin. Then detailed surveys using lines closer together and at different angles are run over areas of main interest. These might

be repeated using different procedures and equipment if the initial results are not sufficiently clear. This can take several years, especially when there are seasonal constraints on seismic operations, as in the Arctic. The only way to prove whether or not the reservoir traps contain oil or gas is by drilling.

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A drill rig has two main parts: a mechanical system to raise, lower and turn steel pipe in the drill hole, and a circulation system to pump fluids in and out of the hole. The rock is cut away by a drilling bit attached to the end of hollow drill pipe through which fluid, called "mud" is pumped. The cuttings which are carried to the surface by the mud reveal the kind of rock being drilled. At appropriate times, special tools are lowered into the hole on cables to measure the electrical and other characteristics of the rocks that have been penetrated. The resultant strip charts are called well logs. This information is added to the previous information to refine the geological picture of the basin and decide where to drill next. Thus the ongoing exploration program is an evolutionary process; each step is contingent upon the last one. This is particularly important in the frontier areas like the Arctic where each well costs millions of dollars.

A typical exploration well in the Arctic might be drilled as follows:

Slide 8(a) Using a large-diameter auger drill, a 42-inch hole is dry-drilled to about 60 feet in depth. A 36-inch diameter, double-walled, steel pipe, called a "conductor pipe," is lowered into the hole and

cemented in place. This conductor pipe is refrigerated during the ensuing drilling operation to ensure that the permafrost does not melt under the drilling rig.

Slide 8(b) A 26-inch diameter hole is then drilled through the conductor pipe to a depth of about 500 feet using cold drilling fluid to minimize thawing of the permafrost around the new hole. A 20-inch diameter steel pipe, called a "permafrost string," is cemented in the hole all the way to the surface. A large valve called a "blowout preventer" is installed on the top to control any flow of fluid from below.

Slide 8(c) A 17-1/2-inch hole is then drilled through the permafrost to a competent formation, and a 13-3/8-inch diameter steel pipe, called "surface casing" is cemented to the surface. Another blowout preventer consisting of a series of large valves is then installed on the top. After drilling out the cement in the bottom of this hole and opening up a few feet of new hole, pressure is exerted on the mud in the hole to determine the condition of the well this far. This is called a "formation integrity test" (FIT) which measures the pressure that the rock below the surface casing can hold. This in turn determines how far the well can be drilled before another string of casing must be committed.

Slide 8(d) A 12-1/4-inch diameter hole is then drilled until the limiting pressure on the surface casing seat is approached or some other event, such as penetration of a potential reservoir, is

encountered ... say at 5,000 feet. Then a 9-5/8-inch pipe is run and cemented well up into the surface casing. Another FIT test is conducted on the new casing seat, and drilling is resumed.

This procedure is then repeated once or twice more using successively smaller holes and pipe diameters until final total depth is reached.

Slide 9 As illustrated, this results in a telescoped-looking hole containing multiple casing strings with the last one having a small diameter. This is why an exploratory hole is not often useful for subsequent production purposes. Most primary exploration wells drilled in the Mackenzie Basin have been abandoned by plugging the hole with cement whether discoveries of oil and gas were made or not.

Follow-up wells drilled around a discovery to delineate the extent of the field may be drilled with fewer casing strings because the conditions to be encountered while drilling the holes are better known. Some of these delineation wells may eventually be useful for production purposes.

The Development Process

Development of an oil or gas field consists of drilling wells and building the appropriate surface facilities to prepare the fluids for shipment.

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The development wells are designed mainly for production purposes although some may be used for observation purposes or for disposal of fluids like water and mud. Because the drilling conditions are known from prior discovery and delineation wells, the wells can be drilled and completed quickly and efficiently with a minimum number of constricting casing strings. For example, the shallow permafrost string will not be needed and the surface pipe might be set well down into a relatively deep, competent casing seat. The next string of casing might be set into or completely through the reservoir, in which case it is called "production casing." Another string of tubing suspended from the wellhead is then used to pipe the hydrocarbons to the surface. The diameters of these pipes are designed in accordance with expected production rates.

The number of development wells needed for each field is dependent upon the producibility of the individual wells and their ability to drain the reservoir efficiently. There is no single well spacing which would suit every field. The pattern of well spacing used in the southern basin in Western Canada was dictated more by diverse land ownership than by efficient production practices. This situation will not likely occur in the Frontiers. It is more likely that a minimum number of production wells will be drilled initially and that more will be drilled as production rates decline with reservoir depletion.

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In some instances, particularly in fields with relatively deep reservoirs, the wells can be located in clusters on the surface and diverted below surface to wider locations in the reservoir. As a rough rule-of-thumb, wells drilled beyond 5,000 feet can be angled one foot horizontally for every foot of total vertical depth.

Since the earth's temperature increases with depth, the produced fluids arrive at the surface relatively warm. This requires careful design for wells produced through permafrost to account for any thawing and freezeback that might occur.

After reaching the surface, the produced fluids have to be transported from the wellheads to one or more collection points. This is done through pipelines, called flowlines, which are sized to handle the flow rates of the wells. In the Arctic, the flowlines must be elevated on berms or piles to protect the permafrost from warmth of the fluids.

The collection points are usually located within or near the production area to minimize the lengths of the flowlines and thus alleviate the difficulties associated with transportation of raw production fluids. This is particularly important in the case of natural gas.

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One or more of three major problems must be taken into account in the design of a gas production system: flowline size, slug flow and hydrates.

Very large flowlines may be needed to transport natural gas simply because of its gaseous form. Gas expands considerably as its pressure is reduced. Consequently, the lower the wellhead pressure, the larger the pipeline needed to accommodate the gas production. This is an important consideration in the design of production systems for shallow gas reservoirs which have low initial pressures and for the later stages of depletion of deep reservoirs when the pressure has declined. The alternative to massive flowline systems is installation of compression facilities as close to the wellheads as possible.

Whenever some liquid is associated with gas, a phenomenon known as "slug-flow" can occur. The liquid does not flow as fast as the gas and tends to accumulate in the pipeline, especially at low points. Eventually it plugs off the gas flow and starts to build up back-pressure which then pushes the liquid slug down the pipe at high velocity. It creates surging problems in high pressure gas transmission systems. The best solution is to have the gas/liquid separation facilities located close to the wellhead and to minimize dips in the flowlines.

Hydrate formation is another phenomenon peculiar to natural gas production. Hydrates are formed by hydrocarbons and water which together freeze into a solid that resembles ice, at temperatures and pressures above the freezing point of water alone. Short flowlines, insulation, heat, methanol injection, or combinations thereof, are necessary to overcome hydrate problems.

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At the collection point, the flowlines converge into a system of pipes and valves called a manifold. Testing facilities to measure the flow rates of individual wells are located here. Some separation facilities to separate oil, gas and water may also be located here if the gas plant or oil terminal is very far away.

The purpose of a gas plant is to prepare the natural gas for injection into a major pipeline; in other words, to refine and prepare the natural gas stream to meet pipeline standards. This usually involves "drying" the gas by removing water vapour and any liquid hydrocarbons, removal of contaminants like carbon dioxide and hydrogen sulphide, if any, and then compression to pipeline pressure requirements. Each plant must be designed to suit the specific gas stream and location.

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The Production Process

Slide 17

The productivity of an oil or gas field will tend to decline as the hydrocarbons are produced unless more wells are drilled. In general, it will decline roughly in proportion to the stage of depletion of the reservoir; that is, the productivity would be highest when the field started production, would decline to about half when the field is 50 percent depleted, and would be exhausted when the field is depleted.

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It would be impractical to produce a field this way because it would be uneconomic to build production facilities to handle the initial peak. It is customary to level out the production rate by

underutilizing the full productivity of the initial wells and then adding wells to maintain productivity until the natural decline is allowed to resume.

In any event, it is apparent that the sequence of events in the field is as follows. After development, efforts are made to optimize operations. Producing wells and surface facilities are monitored and adjusted to achieve efficient performance. Usually after several years, a time is reached when more wells may be drilled to sustain production rates. Finally, the operation of that particular oil or gas field is allowed to wind down. This last period might be as long or longer than the preceding periods of level production. Consequently, even though the early production level might seem high ... say 5% depletion per year, indicating a 20-year life for the field at constant production rate ... the actual life of the operation will be much longer. For example, most of the fields in Alberta are still producing, including Turner Valley which was discovered in 1913. The Norman Wells oilfield was discovered in 1920 and will probably last beyond the turn of the century.

I have described the exploration, development and production processes in a sequential fashion and may have left the impression that these activities occur in distinct stages in the field. In actual fact, all of these processes are going on at the same time because

there are several "Producers" involved who are at different stages of operation, and because there can be many oil and gas fields discovered successively.

I will now review the history of Industry activities in the Mackenzie Valley area.

Slide 19 History

The Mackenzie Valley has been known to contain oil since the days of Sir Alexander Mackenzie who explored the area in 1789 and reported seepages on the river bank. The seepages were also noted a century later in 1888 by R. G. McConnell of the Geological Survey of Canada. It was not until 1914, however, that a geologist, T. O. Bosworth, staked three claims near these seepages. Imperial Oil acquired these claims in 1919 and dispatched drilling equipment and crews to the site 50 miles downstream from Fort Norman. The first exploratory well struck oil at a depth of 900 feet in 1920. This was the discovery of the Norman Wells oilfield.

Follow-up drilling resulted in two oil wells and a dry hole. A small refinery was installed in 1921 to refine the crude oil into fuel oil but the local market was too small to support the operation. It was closed down until 1932 when it began operating on a seasonal basis to fuel the mines that were developing around Great Bear Lake and Great Slave Lake. Canada's first products pipeline was built around the Bear River rapids by Imperial in 1939, and it continued to operate until just a few years ago.

In 1942, when the Japanese troops occupied the Aleutian Islands and posed a threat to the North American continent, the Canol Project was approved as a joint Canadian-U.S. project to supply Alaska with fuel from Norman Wells crude. For this project, Imperial crews drilled more than 80 wells in the Norman Wells area during the next few years. A quarter of them were dry and abandoned. Meanwhile, a crude oil pipeline was built from Norman Wells to Whitehorse. After the War, the Whitehorse refinery and the Canol crude line were dismantled, and Norman Wells settled back to supplying the local fuel market.

The discovery of the Leduc oilfield in 1947 drew the attention of the oil industry to central Alberta. For the next ten years, exploration drilling in the Territories was pretty well confined to the area south of Fort Simpson, without notable success.

Then, Western Minerals Limited moved into the Eagle Plains area of the Yukon to the west and a little north of Norman Wells. Their first well, which incidentally was the first well drilled in the Canadian Arctic, was started in April of 1957. It was dry; but a second well drilled during 1959-60 encountered an oil show. Unfortunately, the basin has not lived up to its early promise. After 67 holes have been drilled, nothing of significance has been discovered in the area between the Mackenzie River and the Alaskan border. Drilling has virtually stopped there.

In 1957, the Federal Government promoted northern development. The acreage held under exploration permits in the Territories increased rapidly until 1960 when almost all of the onshore acreage up to the Arctic coast was held.

Seismic surveys started north of Fort Good Hope in 1959, and eleven dry holes were drilled on the Anderson Plains in 1960. Only a few of the 40 holes drilled to date on the Anderson Plains have encountered oil or gas shows.

In 1960 Richfield Oil Corporation drilled at Point Separation at the south end of the Mackenzie Delta. In 1962, Texaco Canada drilled two shallow holes at Nicholson Point on the Arctic coast on the fringe of the Mackenzie Basin. It was not until 1965 that the first hole was drilled in the Mackenzie Delta proper by Gulf, Imperial and Shell, jointly (Reindeer D-27). All were dry and drilling ceased for a time in the coastal area.

The announcement of the Prudhoe Bay discovery in Alaska in 1968 rekindled interest in the Mackenzie Basin. Seismic activity increased and five exploratory holes were drilled north of Inuvik in 1969. Then in January 1970, Imperial discovered oil at Atkinson Point (Atkinson H-25) on the Tuk peninsula. The pace of exploration by Industry increased to a 12-rig level in 1973 and has remained about that level ever since. A total of 114 holes have now been drilled in the Mackenzie Basin, including about 20 delineation holes around discoveries.

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Several discoveries have been announced, including 4 oil, 9 gas, and 4 with both oil and gas. Not all of these will necessarily prove to be commercial. Only three, Taglu, Parsons and Niglintgak have been proposed for development.

<u>Oil</u>	<u>Gas</u>	<u>Oil and Gas</u>
Atkinson H-25	Russell H-23	Adgo F-28
Ivik J-26	Taglu G-33	Garry P-04
Mayogiak P-17	Mallik L-38	Kumak K-16
Kugpik O-13	Niglintgak H-30	Niglintgak M-19
	Ya Ya A-28	
	Ya Ya P-53	
	Titalik K-26	
	Parsons F-09	
	Parsons S A-44	

The proved and probable reserves of gas discovered to date in the Mackenzie Basin have been estimated by petroleum consultants at 4.7 trillion cubic feet; and the ultimate gas potential of the Basin has been estimated to be more than 40 trillion cubic feet.

No estimates of total proven oil reserves of the Mackenzie Basin have been given, mainly because the discoveries have not been delineated. The ultimate oil potential has been estimated by McCrossan & Porter for the Canadian Society of Petroleum Geologists to be 8 billion barrels.

Future

It now appears that most of the remaining potential of the Mackenzie Basin lies under the Beaufort Sea. The onshore portion of the exploration play has matured, with most of the seismic work having

been done and most of the significant drilling prospects having been drilled. While some onshore exploration activity will continue for a number of years, it is likely that the major exploration effort will shift towards offshore. Imperial and Sun Oil have already drilled a total of ten wells from artificial islands in the Sea. Imperial plans to construct three more islands this year, and Canmar has announced plans to drill two holes in deeper water using floating drillships. Considering the very high unit costs of drilling in the Beaufort Sea, it is unlikely that more than five exploratory holes will be drilled offshore during each of the next few years.

We cannot be more specific about exploration plans for the Mackenzie Basin. As previously stated, exploration is an evolutionary process with each step being contingent upon the preceding one. Results cannot be scheduled.

RH:mm

PERSONAL RESUME

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BORN: 1926, Toronto, Ontario

EDUCATION: B.A.Sc. Engineering, University of Toronto, 1949

EMPLOYED: Imperial Oil Limited, 26 years

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EXPERIENCE: 1949-1973 - Reservoir engineering assignments and studies in Calgary and on loan to Esso Production Research Company, Tulsa, Oklahoma, culminating in appointment as Division Reservoir Engineer, Edmonton in 1955. Appointed Technical Advisor to Standard Oil of New Jersey (now Exxon Corp.) in 1967 and in 1969 returned to Imperial as Production Manager based in Edmonton. Moved to Calgary in 1972 as Operations Manager - Frontiers, responsible for drilling activities in Arctic areas.

1973-present - Corporate Manager - Arctic, responsible for overall corporate activities of Imperial Oil in the Arctic region.

